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## CHARACTERIZATION OF UPPER PALAEOZOIC ORGANIC-RICH UNITS IN SVALBARD: IMPLICATIONS FOR THE PETROLEUM SYSTEMS OF THE NORWEGIAN BARENTS SHELF

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*Recent discoveries of hydrocarbons along the western margin of the Norwegian Barents Shelf have emphasised the need for a better understanding of the source rock potential of the Upper Palaeozoic succession. In this study, a comprehensive set of organic geochemical data have been collected from the Carboniferous – Permian interval outcropping on Svalbard in order to re-assess the offshore potential. Four stratigraphic levels with organic-rich facies have been identified: (i) Lower Carboniferous (Mississippian) fluvio-lacustrine intervals with TOC between 1 and 75 wt.% and a cumulative organic-rich section more than 100 m thick; (ii) Upper Carboniferous (Pennsylvanian) evaporite-associated marine shales and organic-rich carbonates with TOC up to 20 wt.%; (iii) a widespread lowermost Permian organic-rich carbonate unit, 2–10 m thick, with 1–10 wt. % TOC; and (iv) Lower Permian organic-rich marine shales with an average TOC content of 10 wt.%.*

*Petroleum can potentially be tied to organic-rich facies at formation level based on the gammacerane index,  $\delta^{13}\text{C}$  of the aromatic fraction and/or the Pr/Ph ratio. Relatively heavy  $\delta^{13}\text{C}$  values, a low gammacerane index and high Pr/Ph ratios characterize Lower Carboniferous non-marine sediments, whereas evaporite-associated facies have lighter  $\delta^{13}\text{C}$ , a higher gammacerane index and lower Pr/Ph ratios.*

### INTRODUCTION

The Norwegian part of the Barents Shelf covers an area of more than 300,000 km<sup>2</sup> and is still considered a frontier petroleum province, with only 145 exploration wells drilled and two fields in production. In a recent update, the Norwegian authorities estimated that more than 60% of the undiscovered petroleum resources

on the Norwegian continental shelf are located in the Barents Sea, and that 60–80% of those are in Triassic and older stratigraphic units (NPD, 2018).

The Upper Palaeozoic succession in the western Barents Sea consists of four second-order depositional sequences, each corresponding to a group in the lithostratigraphic scheme for the Norwegian Barents Sea (Figs 1, 2; Larssen *et al.*, 2005). The four-fold division of the succession reflects long (15–50 Ma) periods of relatively stable depositional conditions on the central Pangean shelf separated by abrupt intervals of change (Stemmerik and Worsley, 2005). The Lower Carboniferous Billefjorden Group (Fig. 2) is up to 600

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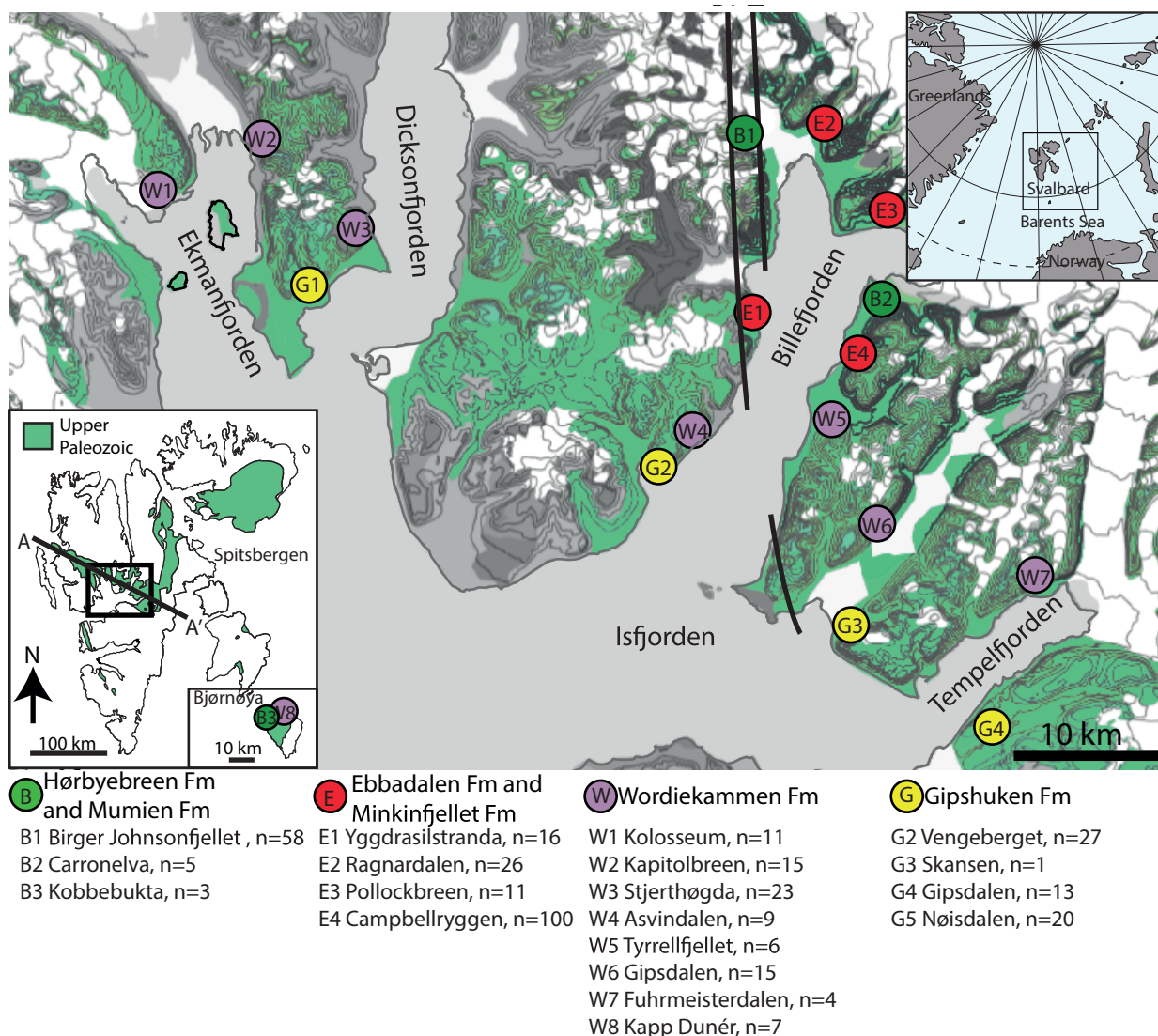
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**Key words:** Norway, Barents Sea, Svalbard, Spitsbergen, Upper Palaeozoic, source rocks, petroleum, geochemistry, gammacerane index, biomarkers, isotope ratios.



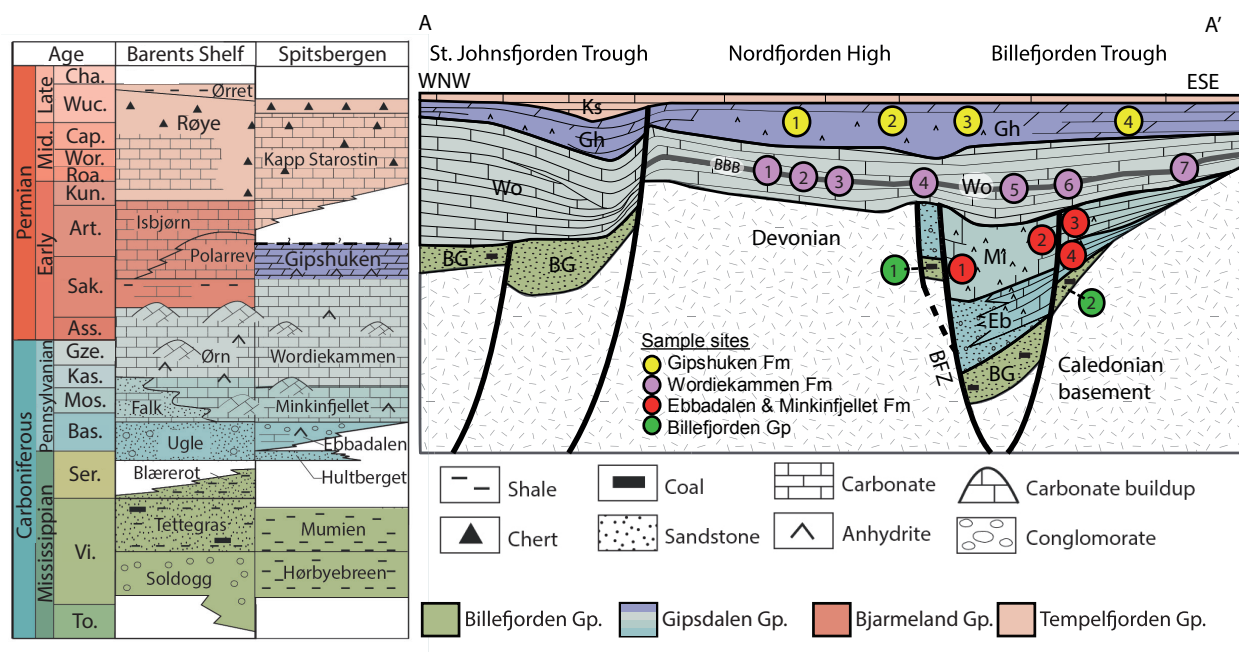
**Fig. 1. Map of sample locations in Central Svalbard and on Bjørnøya. The Billefjorden Fault Zone (BFZ) is marked by black lines. Sample sites are marked by circles. The number of analyzed samples at each site is summarised at the bottom of the figure.**

m thick and is dominated by fluvial deposits including widespread coal layers and corresponds to deposition in a humid tropical climate (van Koeven and Karlsen, 2011). The up to 1500 m thick mid-Carboniferous – Lower Permian Gipsdalen Group consists of a lower, continental to marginal-marine syn-rift succession of coarse-grained siliciclastics and evaporites, and a regionally widespread upper interval of warm-water carbonates. Deposition took place in a warm and arid setting (Stemmerik and Worsley, 2005). The overlying Lower Permian Bjarmeland Group is up to 500 m thick and is composed of cool-water carbonates and interbedded marine shales deposited in a temperate setting. The up to 900 m thick Lower – Upper Permian Tempelfjorden Group is characterized by spiculites and silicified limestones deposited in deeper and cooler shelfal environments (Blomeier *et al.*, 2011).

Three generalized exploration models have been proposed for the Upper Palaeozoic succession on

the western Barents Shelf based on the integration of offshore data with studies of outcrops of the time-equivalent succession on Svalbard in the uplifted NW margin of the Barents Shelf (Fig. 1) (NPD, 2018). Models with Lower Carboniferous Billefjorden fluvial sandstones and Upper Carboniferous – Lower Permian Gipsdalen warm-water carbonates are so far unconfirmed. However, recent discoveries of petroleum in karstified Permian carbonates and spiculites in the Gohta and Alta areas along the western margin of the Norwegian Barents Shelf have confirmed the significance of these stratigraphic intervals as petroleum reservoirs, and have emphasised the need for a better understanding of the petroleum source potential of the Upper Palaeozoic succession in this part of the Arctic.

Play models with Upper Carboniferous – Permian carbonates and spiculites as reservoirs depend on the assumed presence of intra-platform source rocks in the



**Fig. 2 (left). Stratigraphy of Spitsbergen and the Barents Shelf; and (right) simplified west-east cross-section across central Spitsbergen A-A' (profile location in Fig. 1 inset). The cross-section shows the major tectonic elements, the lithostratigraphic units and the dominant lithologies. BG: Billefjorden Group, Eb, Ebbadalen Formation, Mi: Minkinfjellet Formation, Wo: Wordiekammen Formation, BBB: Brucebyen Beds, Gh: Gipshuken Formation, Ks: Kapp Starostin Formation, BFZ: Billefjorden Fault Zone (modified from Hüneke et al., 2001).**

Norwegian Barents Shelf. However, their presence is poorly constrained and very little information exists about their quality. The only Upper Palaeozoic interval with documented petroleum source potential is the coal-bearing Billefjorden Group at the base of the succession. This interval has been studied in outcrops in Svalbard (Figs 1, 2) (Abdullah et al., 1988; van Koeven and Karlsen, 2011). From outcrop studies on Svalbard, it has also been suggested that an organic-rich interval in the Upper Carboniferous – Lower Permian carbonate platform succession may have petroleum source potential.

In this study, a comprehensive set of organic geochemical data, including biomarker and isotope data, have been collected from the Carboniferous – Lower Permian succession in Svalbard, and has been integrated with analyses of depositional and tectonic settings to provide a better understanding of the source potential in the adjacent offshore areas. Focus was on organic-rich intervals in the non-marine Billefjorden Group and the marine parts of the overlying Gipsdalen Group, particularly successions of interbedded carbonates and  $\text{CaSO}_4$ -rich evaporites, since they were easy to identify seismically on the shelf. Three stratigraphic levels with source-rock potential in the marine, mid-Carboniferous to Lower Permian Gipsdalen Group have been identified and characterized, of which two are new. The marine organic-rich facies were deposited in a broad range of shallow-shelf environments, from semi-arid,

evaporite-associated to open-marine, and accordingly geochemical fingerprinting can be used to distinguish oil originating from the different types of marine facies.

## GEOLOGICAL SETTING

Outcropping rocks on the Svalbard archipelago are widely used as analogues for the deeply-buried equivalents in offshore areas of the western Barents Shelf (Figs 1, 2) (e.g. Abay et al., 2017; Jafarian et al., 2017). During the Late Palaeozoic, the Barents Shelf formed part of a large-scale, east-west oriented continental shelf along the northern margin of Pangea extending westwards across northern Greenland to Arctic Canada and eastwards to the Timan-Pechora Basin in Arctic Russia. The entire region drifted northwards during the Carboniferous and Permian and, in concert with an ongoing transgression from the NE, resulted in overall shifts in depositional environments as reflected in the lithostratigraphic division of the succession (Stemmerik, 2000; Stemmerik and Worsley, 2005).

Early Carboniferous (Tournaisian-Viséan) deposition occurred in continental basins in a warm and humid climate. Fluvial sandstones, coals and lacustrine sediments of the Billefjorden Group were deposited in extensional basins across the western Barents Shelf including Svalbard (Steel and Worsley, 1984). To the east, these sediments pass into marine deposits in the Russian sector of the Barents Shelf (Stemmerik, 2000).



**Table 1. Applied methods and number of samples analysed in the present study.**

Group/Formation	Rock-Eval pyrolysis	Extraction of organic material (EOM)	MS of aromatic and saturated fractions	GC	GC/MS	PyGC
Kapp Starostin Formation	22	-	-	-	-	-
Gipshuken Formation Marine	20	9	9	9	9	3
Gipshuken Formation Evaporitic	19	12	12	12	12	-
Wordiekammen Formation	93	25	25	25	25	4
Ebbadalen Formation and Minkinfjellet Formation	175	36	36	36	36	3
Mumien Formation	21	17	17	17	17	5
Hørbyebreen Formation	46	11	11	11	11	5

Following early Serphukovian uplift and erosion, subsidence began in narrow half-grabens during the late Serpukhovian, and the region was transgressed in the Bashkirian. The climate was warm and arid, and the ongoing transgression, modulated by high frequency sea-level changes related to the Gondwanaland glaciations, resulted in the deposition of the Gipsdalen Group sedimentary succession (e.g. Stemmerik, 2000; Larssen *et al.*, 2005). At the base of the succession are continental conglomerates and sandstones, followed by interbedded marine evaporites and carbonates, and ending with widespread open-marine warm-water carbonates including localized build-ups during the Late Carboniferous to Early Permian. During the middle Permian, the climate gradually became cooler and deposition of cool-water carbonates and marine shales, and then spiculites and cool-water carbonates, dominated the later parts of the Permian (e.g. Steel and Worsley, 1984; Larssen *et al.*, 2005).

On Spitsbergen, the largest island in Svalbard, extension on north-south oriented faults resulted in a series of westwards tilted half-grabens (Figs 1, 2). The Gipsdalen Group syn-rift deposits of the Ebbadalen and Minkinfjellet Formations (Fig. 2) were deposited in the rapidly-subsiding Billefjorden and St. Johnsfjorden Troughs (Steel and Worsley, 1984). As tectonic activity ceased during the latest Carboniferous, the depositional area expanded and the overlying Wordiekammen and Gipshuken Formations (Fig. 2) are characterized by more widespread, stable platform carbonates with less thickness and facies variations.

The Carboniferous and Permian succession in central Spitsbergen has an accumulated thickness of approximately 2000 m in the troughs and 750 m on the highs (Braathen *et al.*, 2011; Steel and Worsley, 1984; Dallmann *et al.*, 1999). In central and eastern Spitsbergen, to the north and east of the Central Tertiary Basin, maximum burial occurred during the Early Cretaceous (Albian) with an overburden of

approximately 2000 m of Mesozoic sediments (Mørk and Worsley, 2006; Ogata *et al.*, 2012; Marshall *et al.*, 2015). In the West Spitsbergen fold-and-thrust belt, and in the Central Tertiary Basin, maximum burial occurred during the Oligocene, prior to the start of extension between Svalbard and Greenland (Nøttvedt *et al.*, 1993). Approximately 2000 m of Paleogene sediments are preserved in the Central Tertiary Basin, and Marshall *et al.* (2015) estimated that an additional 1000 m of sediments were removed during Pliocene – Quaternary uplift of Svalbard. The present-day geothermal gradient is 33–40 °C/km in the Central Tertiary Basin (Braathen *et al.*, 2012), and may have been up to 50 °C/km during maximum burial (e.g. Marshall *et al.*, 2015).

## MATERIALS AND METHODS

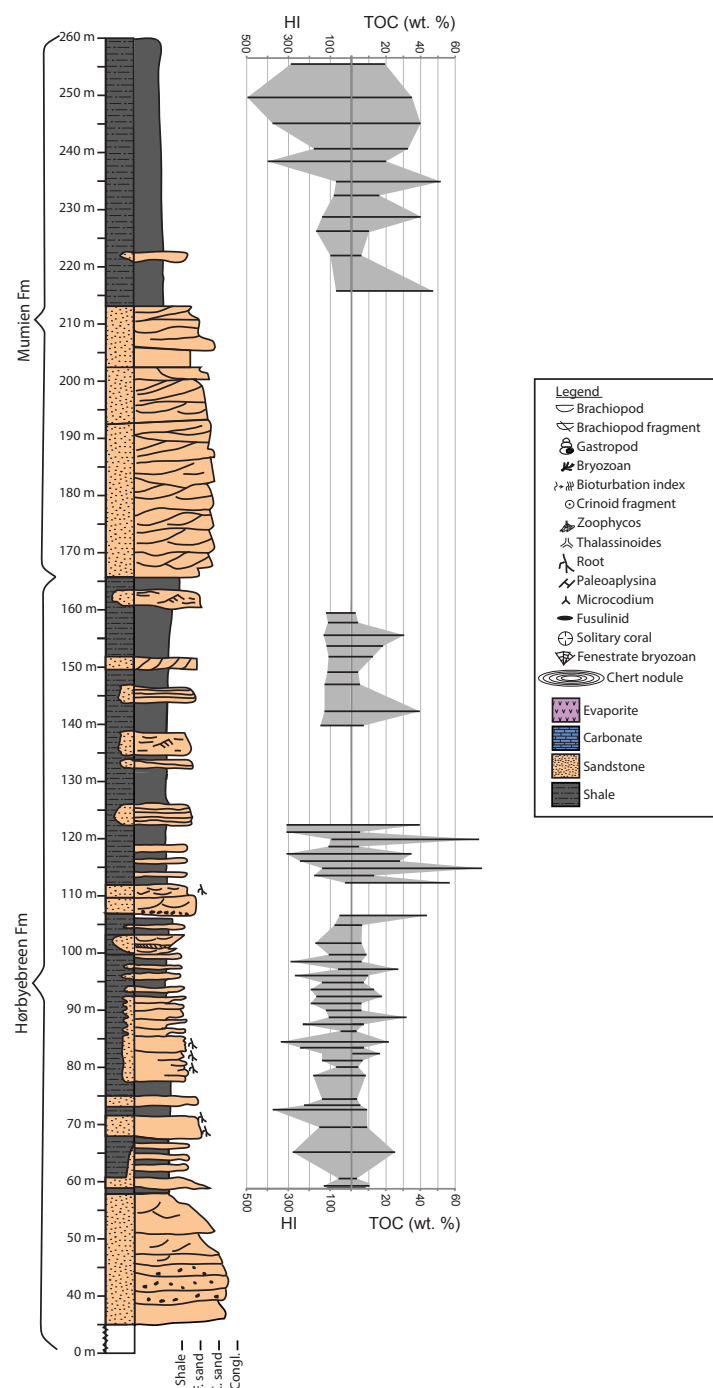
### Sampling and sedimentological logging

Sedimentological logging and sampling were carried out using standard techniques during winter and summer field work. Sample locations on Spitsbergen were chosen to ensure the best possible geographical and stratigraphic coverage of the Upper Palaeozoic succession, with a focus on the Billefjorden Trough and the Nordfjorden High in central Spitsbergen (Figs 1, 2).

Sampling focused on dark grey – black, fine-grained siliciclastics and carbonates. For thinner beds, the entire unit was sampled. Beds thicker than 50 cm were sampled at the top and bottom, and beds thicker than 1 m were sampled for every 50 cm, including the base and top. A total of 395 samples were analyzed using Rock-Eval pyrolysis for source rock screening, of which 110 samples were analyzed in more detail (Table 1).

### Billefjorden Group (Lower Carboniferous)

The majority of the analyzed samples from this stratigraphic interval (46 out of 65) were recovered



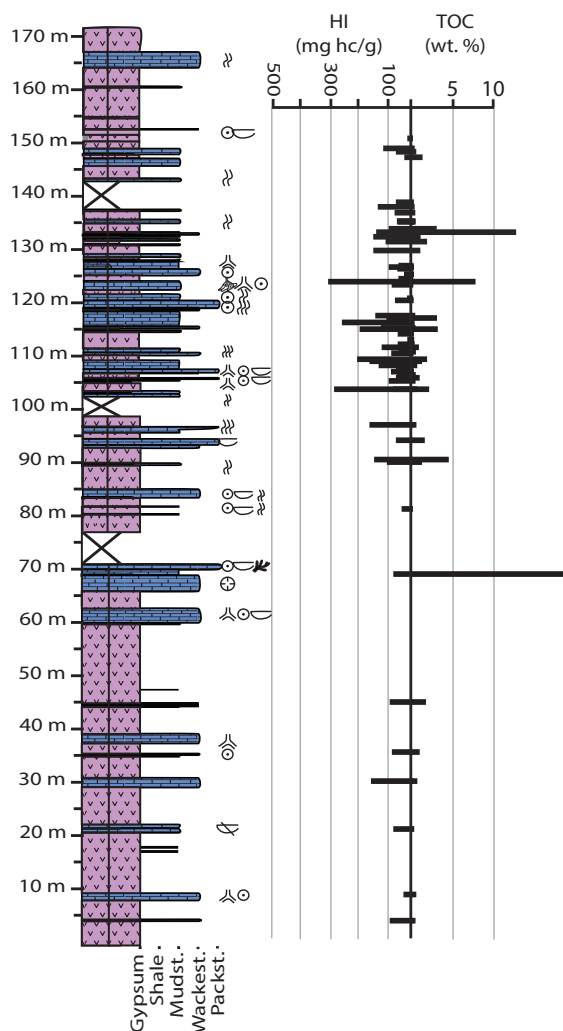
**Fig. 3. Sedimentological log of the Hørbybreen and Mumien Formations at Birger Johnsonfjellet showing stratigraphic distribution of screening data. Compiled using information from Gjelberg (1984). For location, see Fig. 1.**

from the Hørbybreen and Mumien Formations in a ca. 260 m long section at Birger Johnsonfjellet (B, Fig. 1; logged section in Fig. 3). Additional samples from adjacent localities along Billefjorden were analyzed together with a single sample from Bjørnøya, 450 km to the south, to investigate regional variations.

*Gipsdalen Group (mid-Carboniferous – Lower Permian)*

Material from the Bashkirian–Moscovian syn-rift succession was collected in sections in the Billefjorden

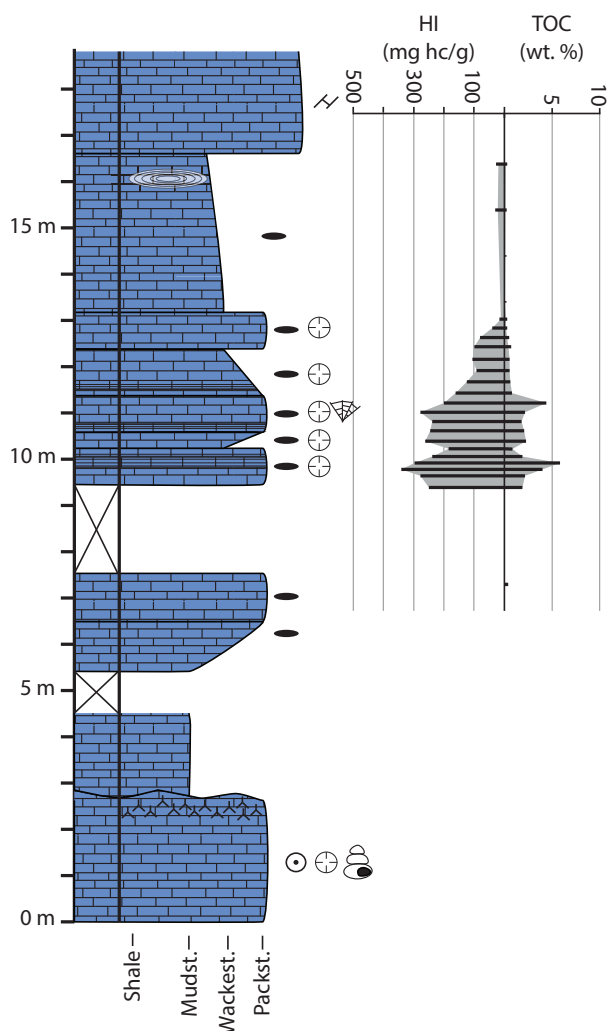
Trough (Figs 1, 2). Material from the marine Bashkirian Trikolorfjellet Member (Ebbadalen Formation) included 33 samples of laminated, organic-rich intervals within  $\text{CaSO}_4$ -evaporites and thin organic-rich shales at the bases and tops of carbonate beds. This material was collected from two sections, each up to 200 m thick, in northernmost Billefjorden (E2 and E3, Fig. 1). At this locality, the Trikolorfjellet Member consists of interbedded 1–10 m thick marine carbonates and  $\text{CaSO}_4$ -evaporites with rare intercalations of continental sabkha deposits (red siltstones with gypsum



**Fig. 4. Sedimentological log and screening data through the Minkinfjellet Formation. For location, see E4 in Fig. 1. For legend, see Fig. 3.**

nodules). Samples from the Moscovian Minkinfjellet Formation consist of organic-rich laminae within evaporites, organic-rich shales deposited between carbonates and evaporites, and organic-rich carbonate mudstones; the great majority were carbonates (Fig. 4). Most of the samples, 61 out of 118, were collected from a 170 m thick section of interbedded marine carbonates and evaporites at Campellyryggen along the east shore of Billefjorden (E4, Fig. 1). Additional samples were collected at outcrops just to the south and north of this location ( $n = 39$ ), at Yggdrasilstranda along the western shore of Billefjorden ( $n = 16$ ), and in Ragnardalen ( $n = 26$ ), north of Billefjorden (Fig. 1).

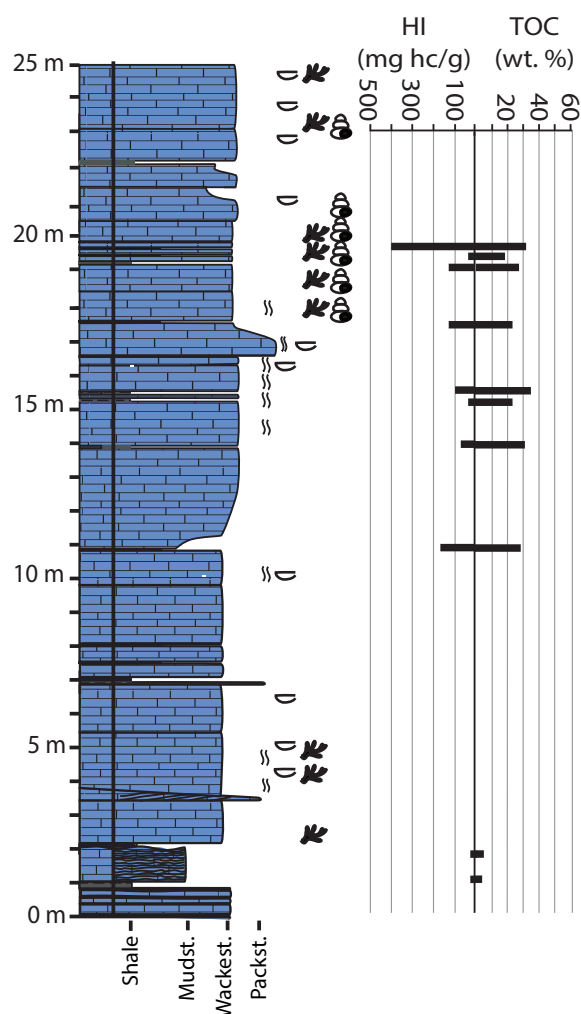
The 2–12 m thick uppermost Gzelian – lowermost Asselian Brucebyen Beds (Fig. 5) form a distinctive interval within an up to 350 m thick succession of cyclic warm-water carbonates. These characterize the Moscovian-Sakmarian Wordiekammen Formation platform carbonates on Spitsbergen (e.g. Ahlborn and



**Fig. 5. Log and screening data through the Brucebyen Beds, Wordiekammen Formation, at the type section. For location, see W5 in Fig. 1. For legend, see Fig. 3.**

Stemmerik, 2015). A total of 90 samples were collected from seven localities along a 70 km east-west transect across central Spitsbergen from Kolosseum in the west to Fuhrmeisterdalen in the east (Fig. 1). The most densely sampled section was W3 in the west (Fig. 5). A few additional samples from similar facies were collected at Bjørnøya (Kapp Duner Formation) (Fig. 1). All the samples were composed of carbonates.

Material from the Lower Permian Gipshuken Formation consisted of shales deposited in two different settings. Shale samples from the lower Vengeberget Member are associated with  $\text{CaSO}_4$ -evaporites and 41 samples were collected from three localities along a transect from Ekmanfjorden to Tempelfjorden (Figs 1, 2). In addition, shales associated with open-marine carbonates were collected from a single section at Nøisdalen, south of Tempelfjorden (Figs 1, 2). This material includes 20 samples of up to 10 cm thick shale beds.



**Fig. 6.** Log and screening data through the marine part of the Gipshuken Formation. For location, see G4 in Fig. 1. For legend, see Fig. 3.

#### *Tempelfjorden Group (Lower – Upper Permian)*

Twenty-five samples of dark marls from the lower part of the Kapp Starostin Formation were screened for organic content and HI. They show an average TOC content of 0.7% and HI of 67 mg HC/g TOC, indicating that the material has no source potential. The samples were not analyzed further.

#### **Geochemical analysis**

Geochemical analyses were carried out at Applied Petroleum Technology (APT), Lillestrøm, Norway, in accordance with the guidelines described in Weiss *et al.* (2000). All samples were screened for their content of total organic matter (TOC) using a Leco SC-632 instrument, and analysed by Rock-Eval pyrolysis in order to determine the kerogen type, maturity and source potential. Samples for further analysis were chosen based on the screening results and analysed by gas chromatography (GC), gas chromatography-

mass spectrometry (GC-MS and GC-MS-MS), and for stable carbon isotope ratios of the saturated and aromatic hydrocarbon fractions. From each formation, a few samples with source potential were analyzed using pyrolysis gas chromatography (Py-GC) in order to evaluate their ability to generate petroleum. The gas-to-oil generation index (GOGI) was calculated as  $(C_1-C_5)/(C_5-C_{36})$ .

Samples for vitrinite reflectance were prepared and measured at the Geological Survey of Denmark and Greenland (GEUS) using standard procedures defined by ICCP and described in Bustin *et al.* (1989). Molybdenum concentrations were measured on selected samples of the Gipshuken Formation using an Innov X Alpha XRF analyser. The samples were powdered, filled in small glass vessels that were covered by plastic film and turned upside down, so that the XRF was measured through the film. The results were evaluated for misleading results by visual comparison of the XRF spectrograms with the expected  $K\alpha$  and  $K\beta$  for molybdenum. Measurements lacking one of the peaks were discarded as false read-outs. Internal Innovex software was used to convert the peaks to concentrations, which were checked against a NIST-2781 standard measured every tenth sample. All standard measurements are within 3 ppm of the expected Mo concentration.

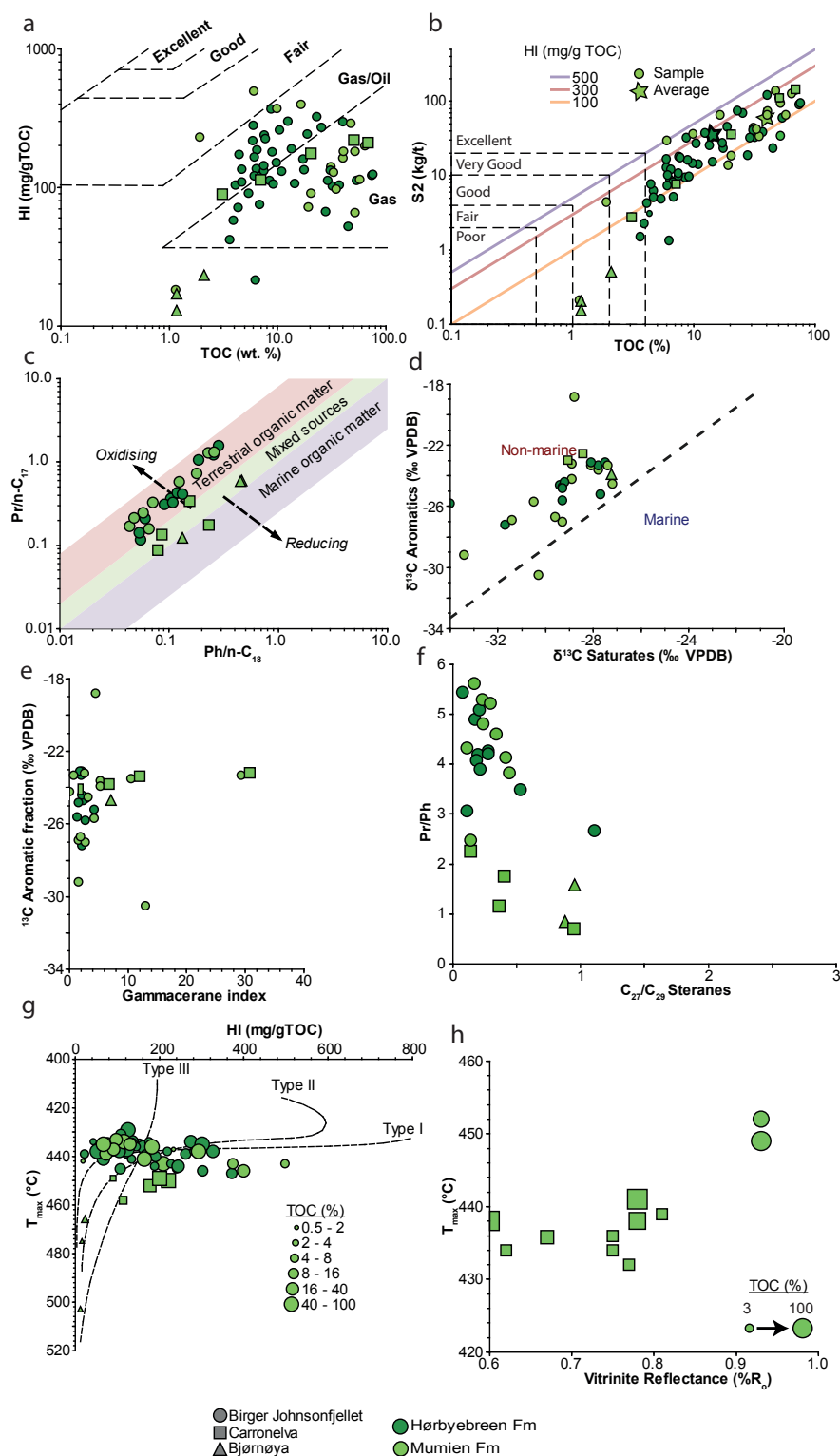
## **RESULTS**

### **Billefjorden Group, Hørbybreen and Mumien Formations (Viséan)**

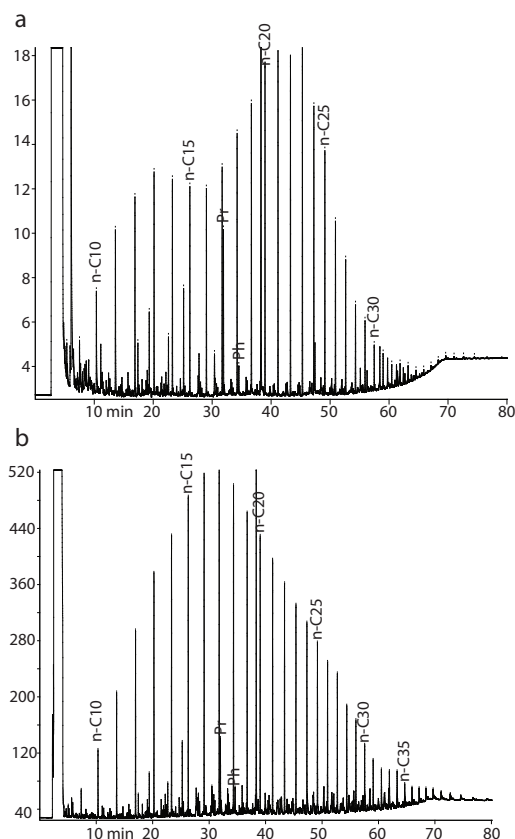
In the key section at Birger Johnsonfjellet (Fig. 3), the Hørbybreen Formation consists of a basal fluvial sandstone unit overlain by a 105 m thick heterolithic floodplain succession (c.f. Gjelberg and Steel, 1981) composed of lacustrine shales, fluvial sandstones and thin coal beds. Organic-rich shales dominate and have an accumulated thickness of approximately 70 m, whereas the coal beds have an accumulated thickness of less than 3 m. The overlying Mumien Formation consists of 50 m of stacked, fluvial channel sandstones overlain by a more than 40 m thick heterolithic interval dominated by organic-rich siltstones containing *Botryococcus* algae, interpreted to reflect deposition in shallow lacustrine environments (Abdullah *et al.*, 1988).

In the analyzed material, TOC values range from 1 to 75 wt.% with most samples between 3 and 10 wt.%, and HI values range from 50 to 375 mg HC /g TOC (Fig. 7a). The most organic-rich facies occur in the middle part of the Hørbybreen Formation (ca. 112–123 m) and the upper part of the Mumien Formation (ca. 215–260 m) (Fig. 3). Material from the Hørbybreen Formation follows two different trend lines in a  $S_2$ -TOC plot (Fig. 7b), with one population





**Fig. 7.** Geochemical cross-plots of samples from the Hørbyebreen and Mumien Formations. (A) Hydrogen index (HI) versus total organic carbon (TOC); note that all the samples are mature and that the initial quality of the samples would have been higher. (B) Cross-plot of S<sub>2</sub> versus TOC for sampled potential source rocks in Svalbard; averages for each formation are illustrated by stars. (C) Cross-plot of pristane/(n-C<sub>17</sub>) versus phytane/(n-C<sub>18</sub>); note that samples from Birger Johnsonfjellet represent footwall locations, while the sediments at Carronnelva and possibly Bjørnøya were deposited within tectonically-controlled depressions (Abdullah *et al.*, 1988). (D) Cross-plot of δ<sup>13</sup>C aromatic hydrocarbon fractions versus saturated hydrocarbon fraction in sample extracts. (E) Cross-plot of δ<sup>13</sup>C of the aromatic fraction against the gammacerane index. (F) Cross-plot of C<sub>27</sub>/C<sub>29</sub> steranes versus pristane/phytane ratio. (G) Cross-plot of HI versus T<sub>max</sub> showing that most samples are within the oil window. (H) Cross-plot of T<sub>max</sub> versus vitrinite reflectance (% R<sub>o</sub>) of samples from Birger Johnsonfjellet and Carronnelva.

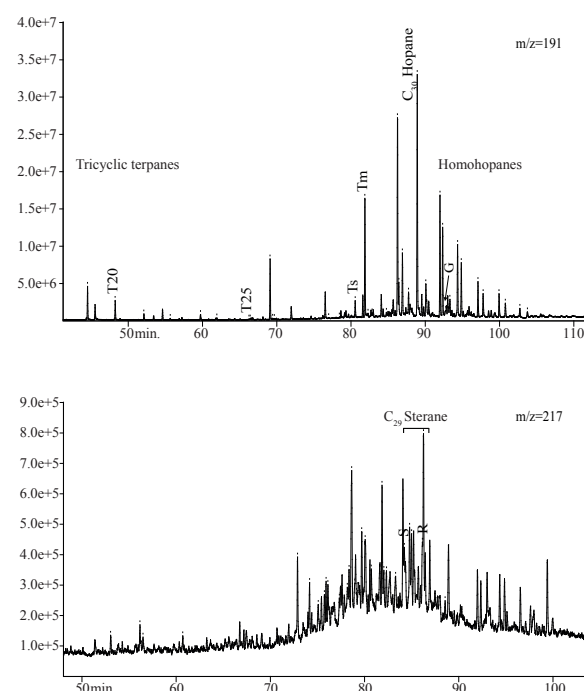


**Fig. 8.** (a) GC-FID chromatogram of a sample from the Mumien Formation at the Birger Johnsonfjellet site; note the bimodal *n*-alkane distribution, the odd predominance (CPI), and the waxy *n*-alkane distribution indicating a possible equally-mixed Type II/III source of organic matter. (b) GC-FID chromatogram of a sample from the Mumien Formation at the Carronnelva location, with a unimodal front-end biased *n*-alkane distribution indicating input to the source rock system of a more uniform marine Type II/“III” source of organic matter.

along the HI line at 300 mg HC/g TOC and the other around the HI line at 100 mg HC/g TOC.

Most Billefjorden Group material shows a unimodal *n*-alkane distribution, dominated by long-chain *n*-alkanes (Fig. 8a); less commonly the *n*-alkane distribution is bimodal (Fig. 8b). The Pr/Ph ratio ranges from 0.8 to 5.5, with the highest values in samples from Birger Johnsonfjellet and lower values in samples from Carronnelva (Fig. 7b), east of Birger Johnsonfjellet and Kobbekbukta at Bjørnøya.  $C_{30}$  steranes are absent from the samples (Fig. 9). In cross-plots of pristane (Pr) versus phytane (Ph) and  $\delta^{13}C$  of the aromatic versus saturated hydrocarbon fractions, the material falls mainly in the terrigenous regime (Figs 7c, 7d).

The analyzed material has been buried to conditions corresponding to the oil window, with  $T_{max}$  values mainly between 430 °C and 450 °C (Fig. 7g) (cf. Peters and Cassa, 1994). Samples from Birger Johnsonfjellet at the Nordfjorden High show vitrinite reflectance



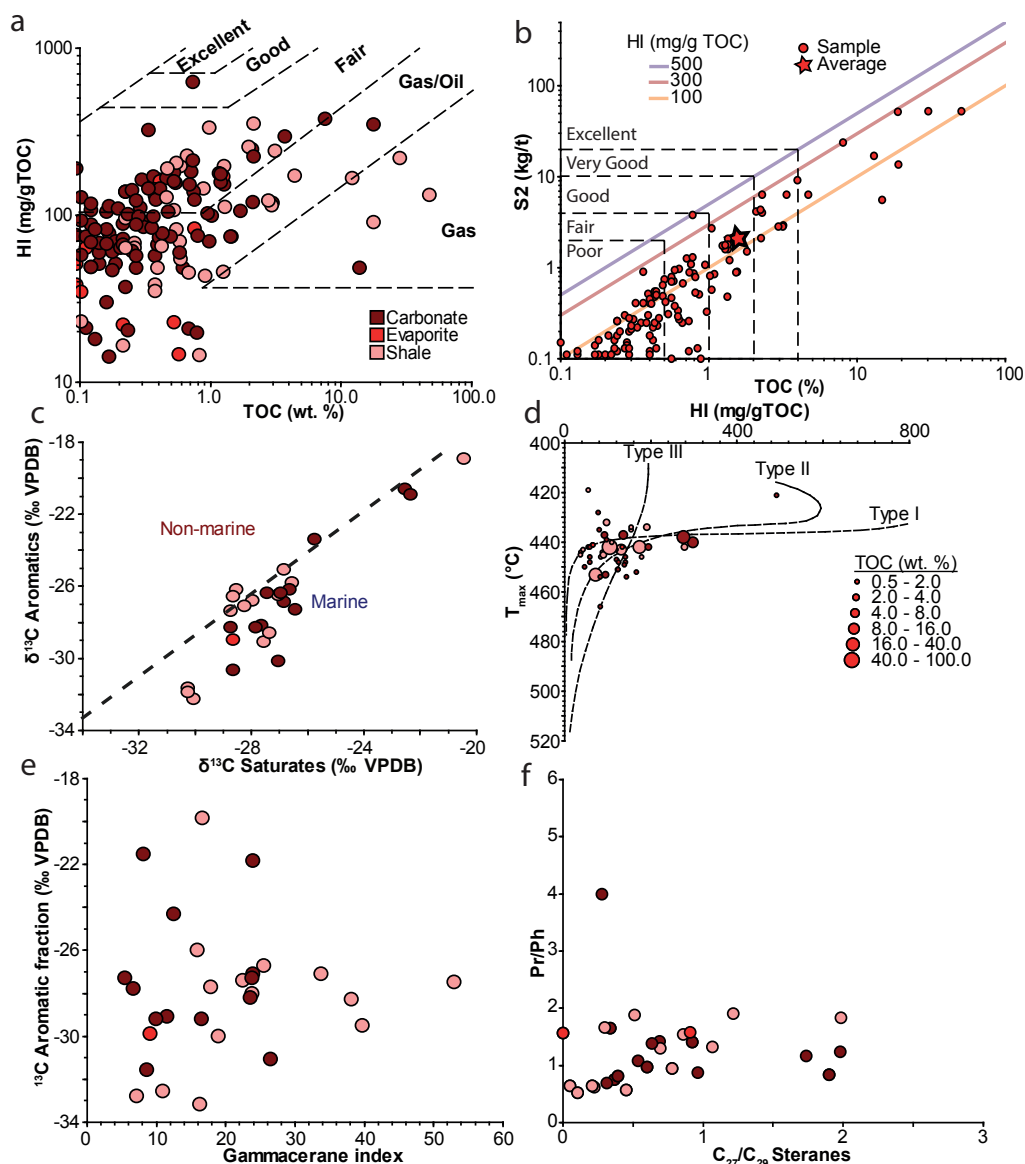
**Fig. 9.** GC-MS ion chromatogram  $m/z = 191$  and  $m/z = 217$  fragmentogram of a representative sample of the Mumien Formation at Birger Johnsonfjellet.

between 0.6 and 0.8%  $R_o$  and  $T_{max}$  values between 430 °C and 440 °C, while samples from Carronnelva in the Billefjorden Trough yielded higher vitrinite reflectance, 0.9%  $R_o$ , and  $T_{max}$  of 450 °C (Fig. 7h).

#### Gipsdalen Group, Ebbadalen and Minkinfjellet Formations (Sepukhovian – Moscovian)

The analyzed material consists of relatively thin, organic-rich shales and carbonates interbedded with much thicker, organic-lean carbonates and evaporites in both the Trikolorfjellet Member (Ebbadalen Formation) and Minkinfjellet Formation. The organic-rich laminae within the evaporites are 1–5 cm thick and occur throughout the succession, and constitute 1–5% of the evaporite beds. TOC values range between 0.5 and 1.5 wt.% and HI values are 40–275 mg HC/g TOC, with an average of 90 mg HC/g TOC (Fig. 10a). The laminated organic-rich shale facies are of similar thickness (1–5 cm) and occur in both the carbonate- and evaporite-dominated units. They constitute around 0.5% of the succession. TOC ranges from 0.5 to 60 wt.%, with most in the range 0.5–1.5 wt.%, and HI values are between 35 and 280 mg HC/g TOC with an average of 90 mg HC/g TOC (Fig. 10a). The shales plot around the HI line at 100 mg HC/g TOC (Fig. 10b).

Organic-rich carbonate facies are limited to those parts of the Minkinfjellet Formation with few evaporites and consist of mud- to wackestones interbedded with 0.5–1 m thick evaporites. The cumulative thickness of the organic-rich beds is approximately 8 m, or 3% of



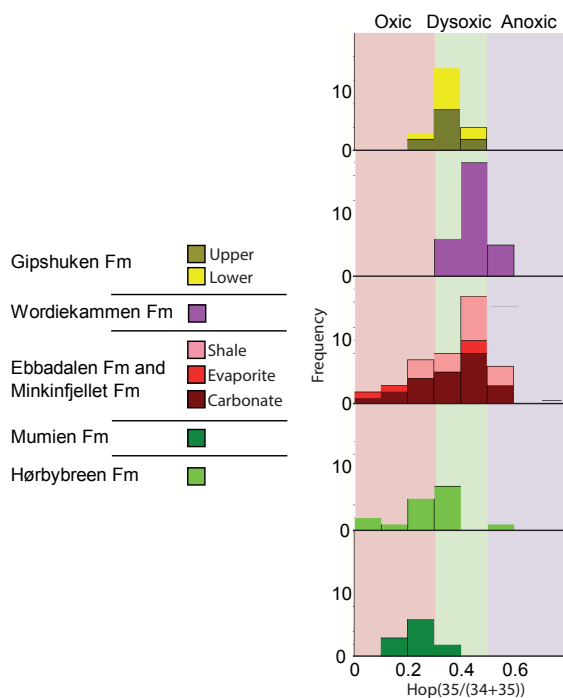
**Fig. 10. Geochemical cross-plots of samples from the Ebbadalen and Minkinfjellet Formations.** (A) Hydrogen index (HI) versus total organic carbon (TOC); note that all the samples are mature and that the initial quality of the samples would have been higher. (B) Cross-plot of  $S_2$  versus TOC for the sampled potential source rocks from Svalbard; averages for each formation are shown by the stars. (C)  $\delta^{13}\text{C}$  of the aromatic hydrocarbon fraction versus the saturated fraction in extracts from the samples. (D) Cross-plot of HI versus  $T_{\text{max}}$  showing that most samples are within the oil window. (E)  $\delta^{13}\text{C}$  of the aromatic fraction plotted against the gammacerane index. (F) Cross-plot of  $C_{27}/C_{29}$  sterane versus the pristane/phytane ratio.

the studied succession. TOC is between 1 and 50%, with most samples containing less than 3 wt.%, and HI values are between 40 and 500 mg HC/g TOC with an average of 80 mg HC/g TOC (Fig. 10a). The samples plot between the HI lines of 100 and 300 mg HC/g TOC (Figs 10b and 10d). The *n*-alkane distribution of the samples is unimodal, peaking at *n*-C<sub>17</sub> (Fig. 12). In all three facies the Pr/Ph ratio ranges from 0.5 to 2, with no evident systematic variations. Highly variable gammacerane indices are recorded for both carbonates and shales, ranging from 8 to 55, whereas the evaporites are less variable, between 10 and 25 (Fig. 10e). In plots of the  $\delta^{13}\text{C}$  of the saturated and aromatic

hydrocarbon fractions (Fig. 10c), all the material falls in the area indicating marine dominated OM. The  $C_{27}/C_{29}$  steranes ratios are between 0 and 2 (Fig. 10f) and the  $C_{35}$  hopane index varies between 0 and 0.5 (Fig. 11).

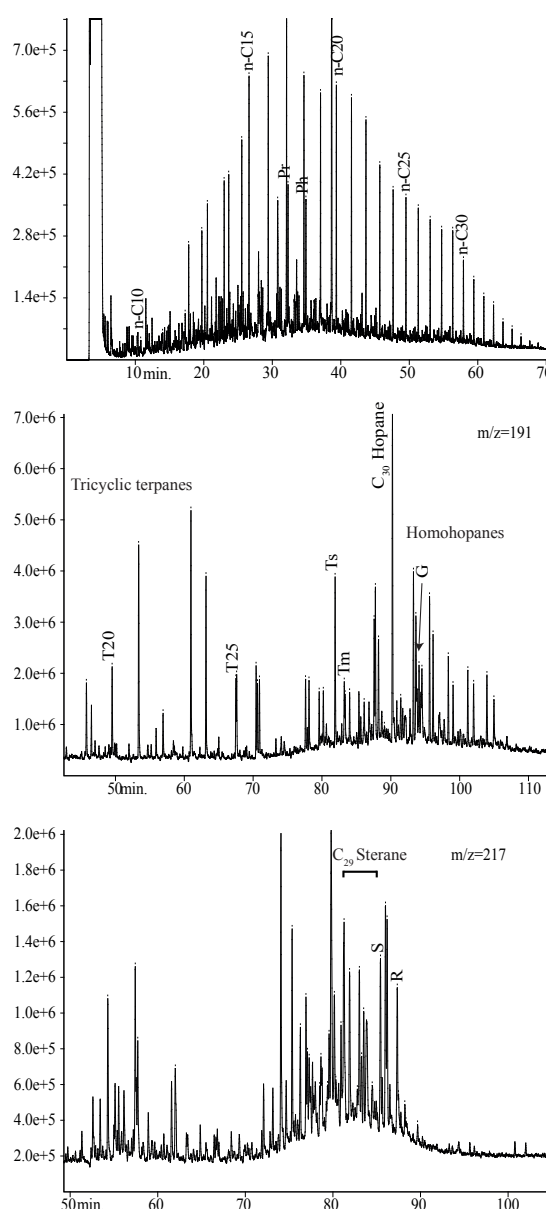
### Gipsdalen Group, Brucebyen Beds (Gzelian-Asselian)

The average TOC content of the analyzed carbonates varies laterally from 0.3 to 4.5 wt.% with an overall average of 2.1 wt.% TOC (Fig. 13a). Even larger stratigraphic variability is evident in most of the sampled sections, as exemplified in Fig. 5 where TOC ranges from 0.2 to 6 wt.%. The material from



**Fig. 11 (above).** Abundance of  $C_{35}$  hopanes with indications of depositional environment (based on Peters and Moldowan, 1991). Note the wide range in the abundance of  $C_{35}$  hopanes in the Ebbadalen and Minkinfjellet Formations indicating deposition in a wide range of environments. See text for discussion.

**Fig. 12 (right).** GC-FID chromatogram and GC-MS ion chromatograms of the saturated fraction,  $m/z = 191$  and  $m/z = 217$  fragmentograms of samples of the organic-rich marine carbonates of the Minkinfjellet Formation. Note “G” for gammacerane. See text for discussion.



Spitsbergen has  $T_{max}$  values between 430 and 460 °C, while the material from Bjørnøya has  $T_{max}$  around 500 °C (Fig. 13d). On a cross-plot of  $S_2$  versus TOC, the analyzed samples plot in two populations: one around the 300 HI line, and the other around the 100 HI line. Overall, the population plotting around the HI line at 300 mg HC/g TOC contains >1 wt.% TOC, while the other population contains <1 wt.% TOC. The average HI is 162 mg HC/g TOC, varying from 70 to 250 mg HC/g TOC (Fig. 13b).

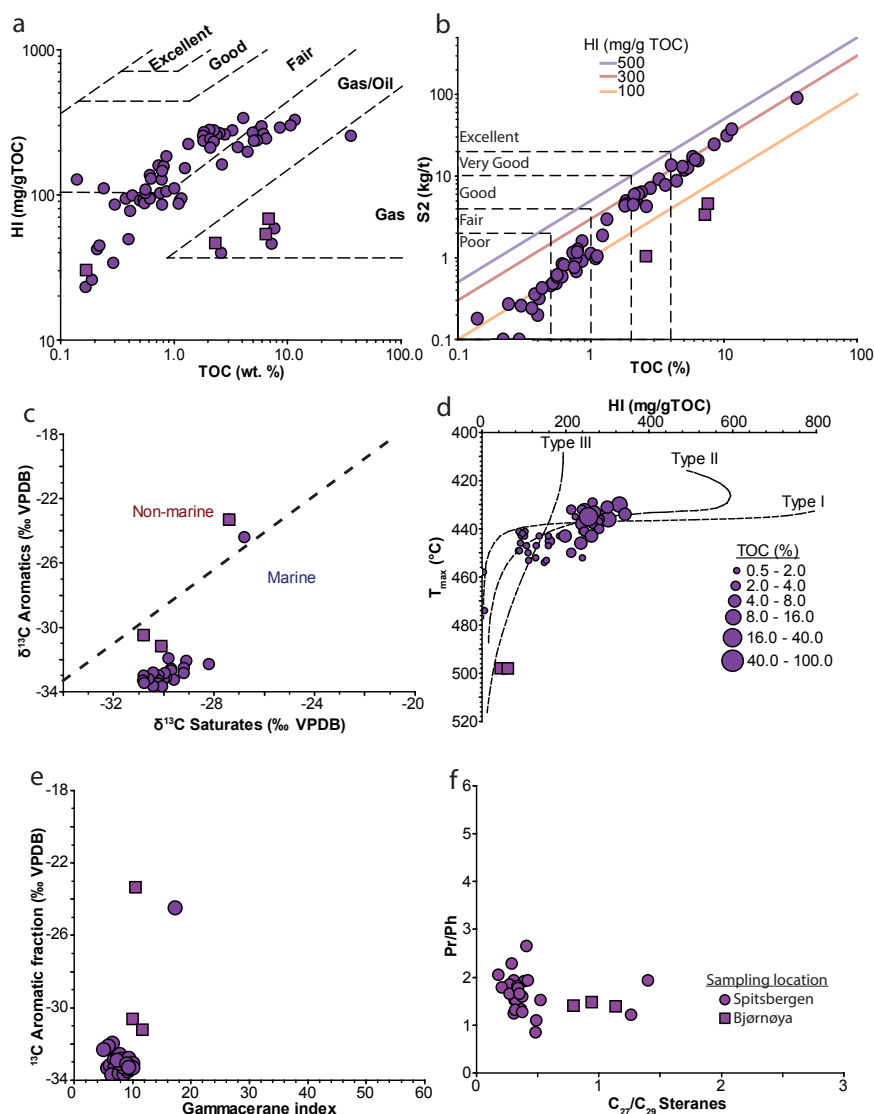
In general, there is very little variability in the biomarker signatures. The Pr/Ph ratios are between 1 and 2, the  $\delta^{13}C$  values of the saturated fraction ranges from -28 to -31‰, with the  $\delta^{13}C$  values of the aromatic hydrocarbon fraction varying from -30 to -34‰, and the gammacerane index shows values from 6 to 12 (Figs 13c, 13e, 14). The  $C_{27}/C_{29}$  sterane ratio varies between 0.2 and 1.5 (Fig. 13f) and the  $C_{35}$  hopane

index between 0.3 and 0.5 (Fig. 11). Most samples from Spitsbergen have  $C_{27}/C_{28}$  sterane ratios around 0.5, while the samples from Bjørnøya have ratios around 0.8 and 1.2 (Fig. 13f).

#### Gipsdalen Group, Gipsbreen Formation (Sakmarian-Artinskian)

Shales associated with evaporites contain 1–10 wt.% TOC with an average of 4.2 wt.%, and have HI values between 200 and 400 mg HC/g TOC (Figs 15a and 15b). In a cross-plot of  $S_2$  versus TOC, they plot between the HI lines of 100 and 300 mg HC/g TOC. The saturated hydrocarbon fraction of the samples ranges from  $\delta^{13}C$  -25 to -31‰, with that of the aromatic fraction showing values from -28 to -32‰ (Fig. 15c). The  $C_{27}/C_{29}$  sterane ratios ranges from 0.1 to 0.9, the gammacerane index ranges from 8 and 32, and Pr/Ph ratio is around 1.5 (Figs 15d, 15f).





**Fig. 13.** Geochemical plots of samples from the Wordiekammen Formation. (A) Hydrogen index (HI) versus total organic carbon (TOC); note that all the samples are mature and that the initial quality of the samples would have been higher. (B) Cross-plot of  $S_2$  versus TOC for sampled potential source rocks in Svalbard; averages for each formation are shown by stars. (C)  $\delta^{13}\text{C}$  of the aromatic versus the saturated fraction extracted from the samples. (D) HI versus  $T_{\text{max}}$  showing that most samples are within the oil window. (E)  $\delta^{13}\text{C}$  of the aromatic fraction plotted against the gammacerane index. (F) Cross-plot of  $C_{27}/C_{29}$  sterane versus pristane / phytane ratio.

The shales associated with marine carbonates contain 1–90 wt.% TOC with an average of 10 wt.%, and HI is in the range from 100 to 350 mg HC/g TOC (Figs 15a and 15b). On a cross-plot of  $S_2$  versus TOC, they plot around the HI line at 300 mg HC/g TOC (Fig. 15c). The hydrocarbons are dominated by short-length  $n$ -alkanes, with a unimodal distribution peaking at  $n\text{-C}_{14}$  (Fig. 16). The saturated hydrocarbon fraction of the material ranges from -25 to -30‰  $\delta^{13}\text{C}$ , and the aromatic hydrocarbon fraction from -28 to -32‰ (Fig. 15c). The  $C_{27}/C_{29}$  sterane ratios vary between 0.2 and 1.25, the gammacerane index varies from 9 and 17, and Pr/Ph is around 1.5 (Figs 15d, 15f). Mo concentrations are high (17–165 ppm).

## DISCUSSION

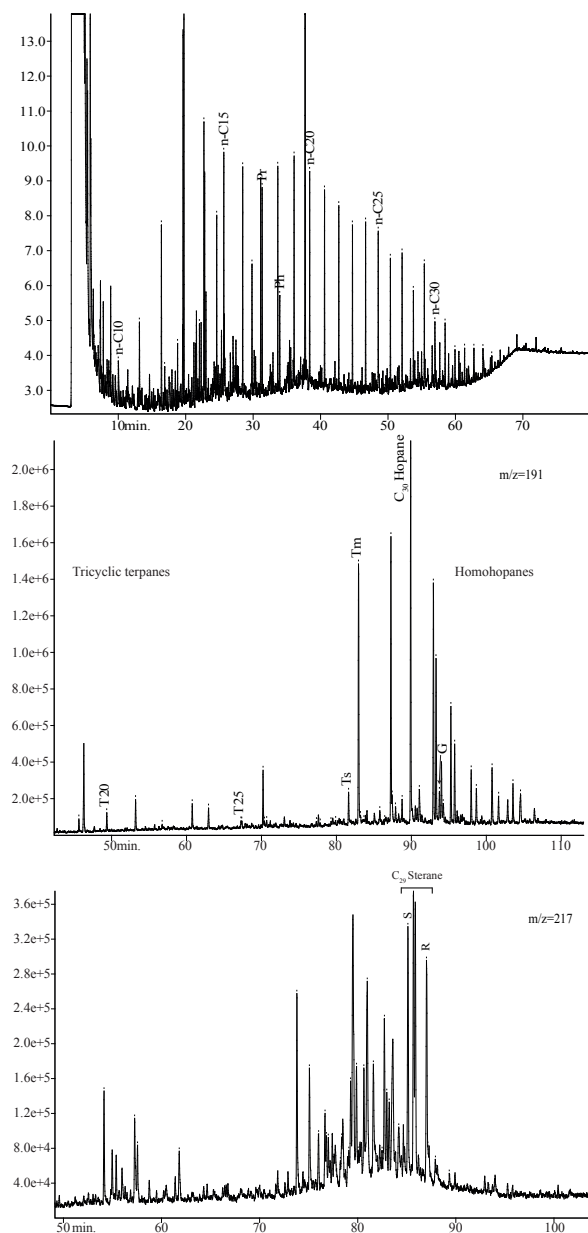
The present data-set provides a comprehensive characterization of Upper Palaeozoic organic-rich sediments in Svalbard and is summarized in Fig. 17. The analyzed material from Spitsbergen shows evidence of maturation corresponding to the oil window, with a normal distribution of  $T_{\text{max}}$  values around 440 °C (Fig. 18). Thus all the analyzed organic-rich intervals have produced petroleum and accordingly have lower  $S_1$  and  $S_2$  values than samples from offshore regions. This is evident when comparing material from the Billefjorden Group from Svalbard with material of similar source type from the Barents Shelf (Fig. 19).

### Billefjorden Group

The combined sedimentological and geochemical data-set indicates that both lateral and stratigraphic variations in source potential and quality of the fluvio-lacustrine sediments in the Billefjorden Group are to be expected. The relatively high Pr/Ph ratios in the samples from Birger Johnsonfjellet indicate oxidizing conditions, at least locally and a more terrestrial input (c.f. Peters *et al.*, 2005) (Fig. 7c). The overall low gammacerane index indicates limited stratification within the water column (Fig. 7e). The low  $C_{27}/C_{29}$  sterane ratio (Fig. 7f), the lack of  $C_{30}$  steranes (Fig. 9) and the low  $C_{35}$  hopane index (Fig. 11) are consistent with deposition in a mainly oxic fluvio-lacustrine environment.

The Hørbyebreen Formation shows larger variations of TOC and HI values than the overlying Mumien Formation in accordance with its suggested floodplain origin (Fig. 3; cf. Gjelberg and Steel, 1981). High TOC is recorded in coals deposited in peat swamps, and in lacustrine shales dominated by the colonial alga *Botryococcus brauni* which have higher HI values. This difference in depositional environment is reflected in the  $S_2$ –HI cross-plot where the coaly facies follows the HI line at 100 mg HC/g TOC, and the lacustrine facies the HI line at 300 mg HC/g TOC (Fig. 7b); this most likely relates to facies-controlled differences in the ratio of lacustrine algal material relative to higher plant material. The HI values are highest in the Mumien Formation in accordance with suggested deposition in lacustrine-dominated environments (e.g. Abdullah *et al.*, 1988). However, this shift in depositional environment is not detected in the biomarker data which suggests that the overall composition of the organic matter did not change over time (Fig. 7d).

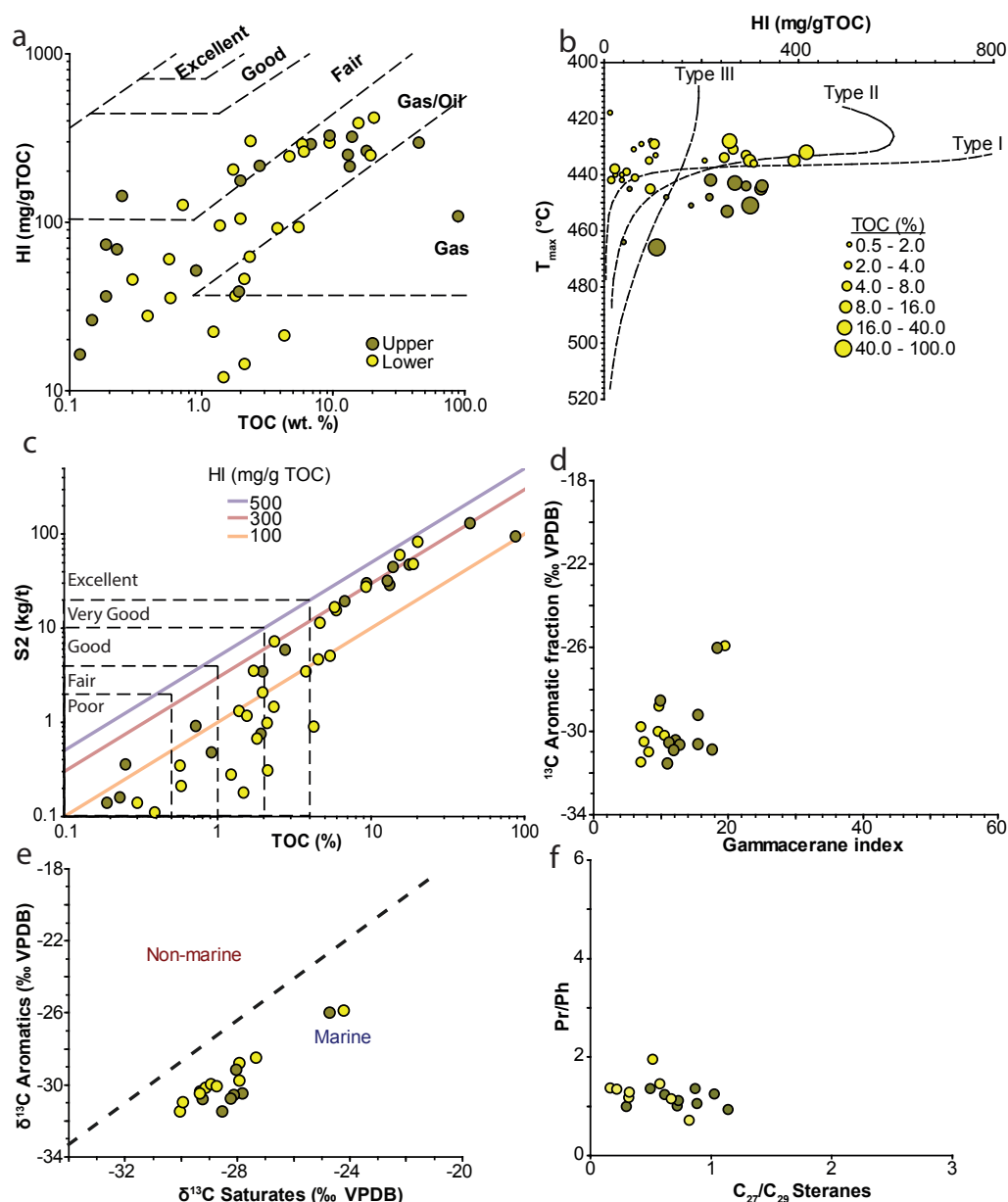
The data-set indicates that lacustrine intervals in the Hørbyebreen and Mumien Formations have the potential to produce both oil and gas. Pyrolysis-GC of organic material from the Birger Johnsonfjellet indicates an average present-day gas-to-oil ratio of 0.2, and suggest that both sedimentary successions are primarily gas/oil prone. The gas to oil prone nature of parts of the Lower Carboniferous shales and coals is supported by the composition of oil from a shallow onshore borehole in the inner part of Billefjorden drilled by Trust Articul in 1992. Analyses from this borehole gave an *n*-alkane signature indicating sourcing from a terrigenous source rock like the Billefjorden Group (Verba, 2007). Carboniferous sediments with source rock potential have been described from offshore wells 7120/2-1, 7128/6-1 and 7281/4-1 (van Koeverden *et al.*, 2010). In these wells, the organic material is of terrigenous origin and resembles the mixed humic and limnic material described from Birger Johnsonfjellet. It is therefore likely that organic-rich fluvio-lacustrine deposits are present over large areas of the SW Barents



**Fig. 14. GC-FID chromatogram and GC-MS ion chromatograms  $m/z = 191$  and  $m/z = 217$  fragmentograms of samples of the Wordiekammen Formation.**

Sea, providing a source for both oil and gas in areas where it is buried to sufficient depths. Eastwards, the Lower Carboniferous succession passes into marine sediments in the Russian part of the Barents Shelf with marine incursions reported to reach the easternmost Norwegian Finnmark Platform (7029/03-U-01) during the Visean (e.g. Bugge *et al.*, 1995).

Thicker successions of Carboniferous lacustrine organic-rich shales have been described from localized lows along the down-dip margin of rotated fault blocks in the rift basins in east Greenland (Stemmerik *et al.*, 1990; Christiansen *et al.*, 1990). The presence of similar facies along fault blocks on the Barents Shelf may add to the Lower Carboniferous source potential.



**Fig. 15.** Geochemical cross-plots of samples from the Gipshuken Formation. (A) Hydrogen index (HI) versus total organic carbon (TOC); note that all the samples are mature and that the initial quality of the samples would have been higher. (B) Cross-plot of  $S_2$  versus TOC for sampled potential source rocks in Svalbard; averages for each formation are shown by stars. (C)  $\delta^{13}C$  of the aromatics versus the saturated fraction extracted from the samples. (D) HI versus  $T_{max}$  showing that most samples are within the oil window. (E)  $\delta^{13}C$  of the aromatic fraction plotted against the gammacerane index. (F) Cross-plot of  $C_{27}/C_{29}$  sterane versus pristane / phytane ratio.

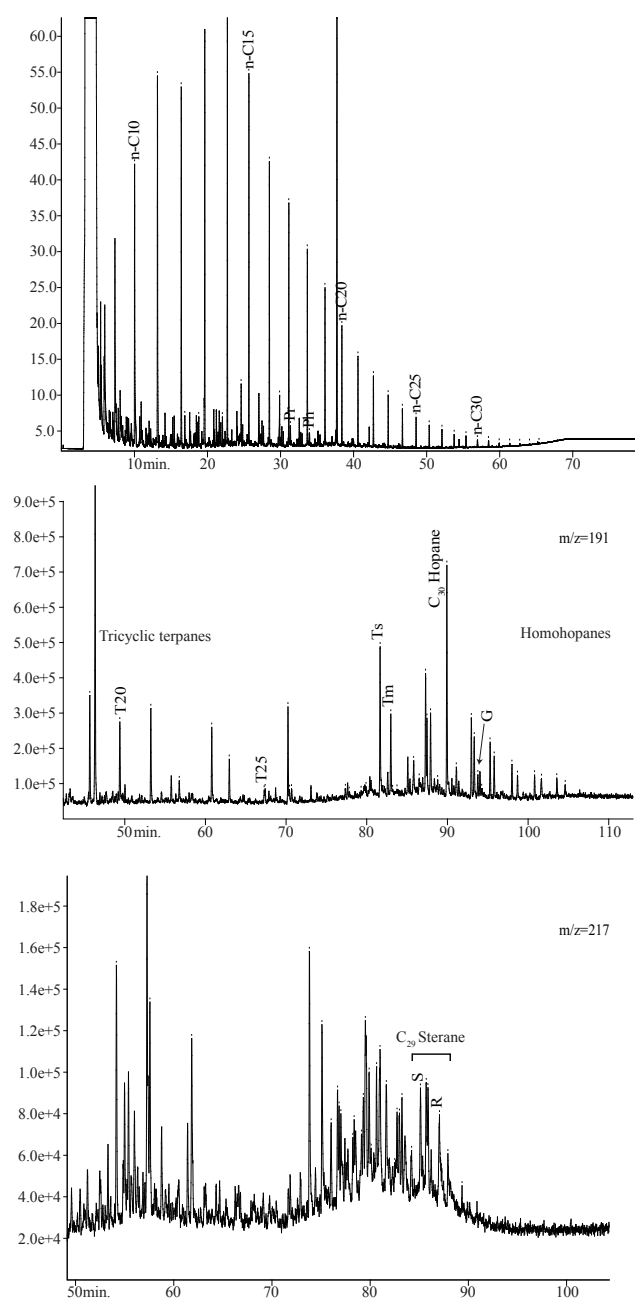
However, no such deposits have been described from Svalbard, and their preservation potential is also a risk since the tops of the east Greenland successions are frequently eroded by coarse-grained alluvial and fluvial conglomerates and sandstones (Stemmerik *et al.*, 1990).

### Gipsdalen Group

The fine-grained, organic-rich facies in the Gipsdalen Group were deposited in a range of marine shelf environments, reflecting shifts in both tectonic setting and climate over time.

The geochemical data-set derived from the evaporitic Trikolorfjellet and Minkinfjellet synrift succession indicates that all the analyzed samples are dominated by marine OM possibly with a slightly higher input of terrigenous organic material in the shales and overall better preservation of OM in the carbonate facies, as indicated by their different distributions relative to the HI trend lines. The mix of marine and terrigenous OM is also evident from the high variability in the  $C_{27}/C_{29}$  steranes ratios and  $C_{35}$  hopane index (Figs 9 and 10f). The relatively high gammacerane index of some shales and carbonates

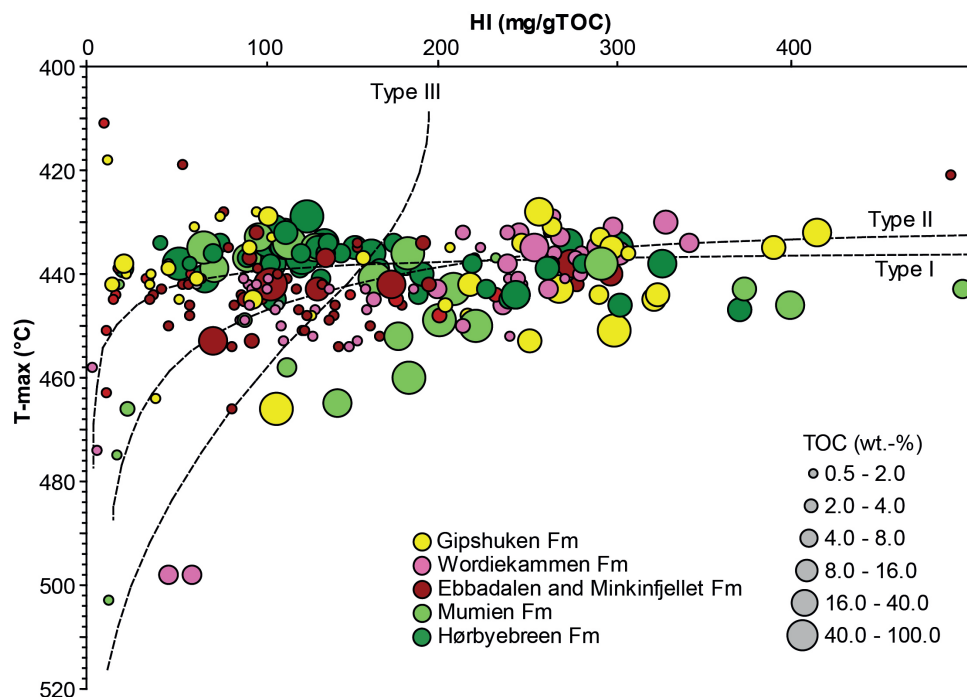
**Fig. 16. GC-FID chromatogram and GC-MS  $m/z$  =191 and  $m/z$  =217 fragmentograms, representative of the marine shales in the Gipshuken Formation at Nøisdalen (G4 in Fig. 1).**



	Litho-stratigraphy	Continental		Marine		Net source thickness (m)	TOC (wt. %)						Hydrogen index					
		Flood-plain	Lacustrine	Restricted	Shallow shelf		1	10	10 <sup>2</sup>	5	10	15	20	25	30	100	300	500
Permian	Lopingian	Tempelfjorden	Ks															
	Guadalupian																	
	Cisuralian	Gipsdalen	Gh															
Carboniferous	Pennsylvanian		Wo															
			Mi															
		Eb																
	Mississippian	Mu																
		Billefjorden																
			Hb															

**Fig. 17. Summary diagram for organic-rich deposits in Svalbard, with depositional environments, net source thicknesses, TOC ranges with average indicated, and Hydrogen Index with average indicated.**





**Fig. 18.** HI versus  $T_{\max}$  cross-plot for all the samples collected in Svalbard; note that the samples with  $T_{\max}$  of about 500°C were collected on Bjørnøya, approximately 450 km to the south of the other sample locations. Bjørnøya is considered to have been uplifted by about 4km (Nyland *et al.*, 1992). Most of the samples from Spitsbergen plot within the oil-window and on the trajectory of Type I or II kerogen.

suggests temporary stratification of the water column (Peters *et al.*, 2015). Pyrolysis GC chromatograms of the carbonate samples show an average gas-to-oil ratio of 0.2, indicating that they are primarily oil prone.

The data-set thus indicates that marine intervals in the lower part of the Gipsdalen Group on Spitsbergen have the potential to produce petroleum. Deposition took place in relatively narrow syn-rift basins during a regional Serpukhovian-Bashkirian rift event, and similar basins are recognized seismically across the western Barents Shelf where the time-equivalent syn-rift fill is included in the Ugle and Falk Formations (e.g. Larssen *et al.*, 2005). The data from Svalbard suggest the potential presence of organic-rich intervals with source potential at the base of the Gipsdalen Group across wide areas on the SW Barents Shelf. In the uplifted parts of Spitsbergen, organic-rich facies with source rock potential correspond to 1–3% (8 m) of the succession.

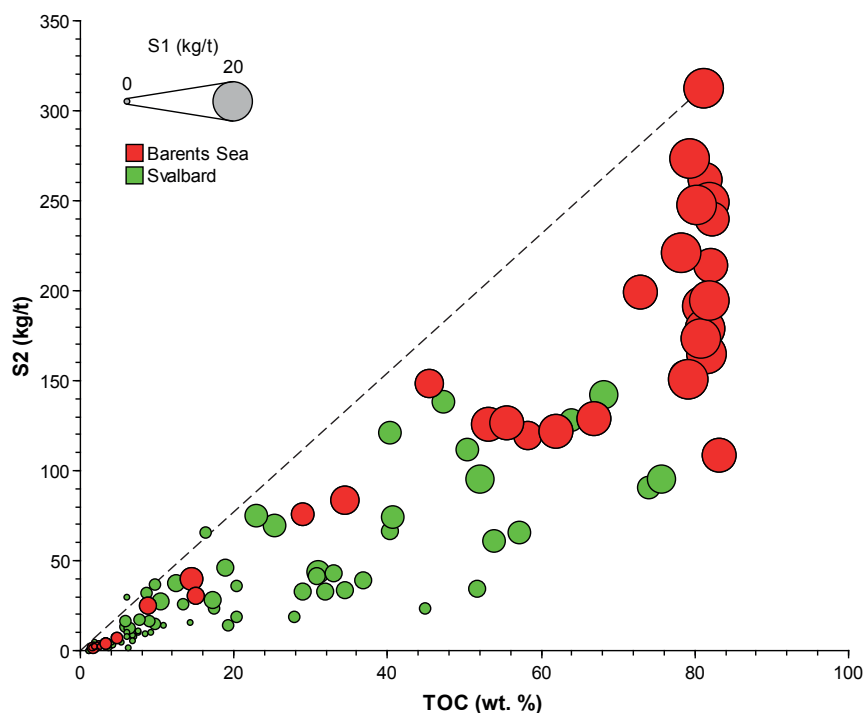
The presence of organic-rich intervals in the thick carbonate platform successions of the upper Gipsdalen Group (the Ørn Formation equivalent) is limited to the Brucebyen Beds, and apparently deposition occurred during a major transgression in the latest Carboniferous to earliest Permian (Nilsson, 1993). The Pr/Ph and  $C_{27}/C_{29}$  sterane ratio, and the cross-plot of  $\delta^{13}C$  of the saturated and aromatic hydrocarbon fractions, all indicate that the organic matter is of marine origin, in accordance with the open-marine setting proposed by Ahlborn and Stemmerik (2015), see Figs 13c, 13e, 13f. This contrasts with earlier studies where the material

is described as terrigenous based mainly on kerogen type (e.g. Hanken and Nielsen, 2015). Identification of organic material based on optically determined kerogen type can be misleading with respect to generated petroleum, especially when working with mature samples (Peters *et al.*, 2005).

The  $\delta^{13}C$  of the aromatic and saturated fractions, gammacerane as well as the Pr/Ph, the  $C_{27}/C_{29}$  sterane ratios and  $C_{35}$  hopane index are uniform, indicating that the composition of the organic matter and the palaeo-depositional environment was relatively uniform across the platform. The observed variability in TOC and HI probably reflects variable oxygenation of the water column across the platform (e.g. Hughes *et al.*, 1995) due to a combination of palaeo-bathymetry and high frequency sea-level fluctuations (e.g. Ahlborn and Stemmerik, 2015) i.e. due to the Gondwanan glaciations. Organic-rich carbonates of similar age also occur at Bjørnøya, some 450 km to the south (Stemmerik *et al.*, 1994), suggesting that this facies is semi-regionally widespread.

The data-set thus indicates that a stratigraphically restricted, but laterally widespread interval in the Gipsdalen carbonate platform succession has the potential to produce petroleum. However, organic-rich carbonates have so far not been encountered in the time-equivalent Ørn Formation on the Barents Shelf (Stemmerik and Worsley, 2005), and it is therefore difficult to judge its regional significance. Pyrolysis GC of the samples indicated an average gas-to-oil ratio of 0.13, indicating that immature equivalents are

**Fig. 19. Cross-plot of  $S_2$  against TOC for samples from the Billefjorden Group in Svalbard and from well 7128/6-1 and 7281/4-1 in the South Barents Sea. The dashed line indicates an HI value of 300 mg HC/g TOC.**



likely to be oil prone. It is noteworthy in this respect that Matapour and Karlsen (2017) and Matapour *et al.* (2018), studying bitumen and oil at the Alta discovery on the Loppa High, recorded a marine Palaeozoic age-specific biomarker petroleum signature, suggesting that at least some of the petroleum at Alta/Gohta is of a Palaeozoic origin.

The geochemical data-set from the lower evaporitic part of the Gipshuken Formation shows many similarities with the data-set obtained from the Trikolorfjellet-Minkinfjellet facies. This indicates that organic-rich shales dominated by marine OM were deposited in proximal evaporitic settings into the Early Permian, suggesting a potentially wider stratigraphic range for these evaporite-dominated organic-rich facies in the offshore areas, e.g. associated with the Fafner unit east of the Loppa High (Ahlborn *et al.*, 2014).

The geochemical data-set derived from the shales associated with marine carbonates in the upper Gipshuken Formation, including the stable carbon isotopes, Pr/Ph and  $C_{27}/C_{29}$  sterane ratios, indicate a marine origin of the OM in this part of the succession. This contrasts with the occasional presence of small woody fragments in the shales, indicating that part of the OM is of terrigenous origin; these woody fragments are possibly erosional products brought into the basin. The high Mo concentrations and the occasional preservation of lamination reflect deposition under anoxic conditions, and interbedding with bioturbated biogenic carbonate pack- and wackestones suggests rapidly fluctuating oxygen levels, possible in a setting close to the storm wave base (Tone Sorento Tågholt, *pers. comm.*, 2018). Thus, anoxic conditions existed at least locally across the Barents Shelf carbonate

platform during the Early Permian, permitting thin organic-rich shales to be deposited. Pyrolysis GC results of the marine shale samples gave an average gas-to-oil ratio of 0.2, indicating that they are primarily oil-prone in the uplifted areas of Spitsbergen.

The organic-rich marine shales in the upper Gipshuken Formation have no reported offshore equivalents in the Bjarmeland Group and their importance is difficult to access. They document that organic material accumulated under anoxic conditions in cool-water, outer ramp settings, and it is possible that upwelling began to influence the shelf during Bjarmeland times.

#### Source-related biomarkers

The source rocks analyzed in this study represent a broad range of depositional environments and this is reflected in the biomarker signatures of the organic matter and the related oils. The different depositional environments in Svalbard can be distinguished using the gammacerane index,  $\delta^{13}C$  values of the aromatic fraction, and the  $C_{27}/C_{29}$  sterane plus the Pr/Ph ratios (Table 2).

The Billefjorden Group is characterized by a combination of relatively heavy  $\delta^{13}C$  values, low gammacerane index and high Pr/Ph ratios. Hydrocarbon signatures from the Carboniferous Minkinfjellet and Ebbadalen Formations are difficult to distinguish from those of the Lower Permian Gipshuken Formation, which is not surprising since the organic-rich sediments were deposited in comparable, evaporitic-dominated environments. The Ebbadalen, Minkinfjellet and Gipshuken Formations, however, are easy to distinguish from the Billefjorden Group

**Table 2. Characteristic parameters for distinguishing the analyzed source rocks.**

Group/Formation	$\delta^{13}\text{C}$	Gammacerane index	Pr/Ph
Gipshuken Formation	-32 – -28	7 – 20	0.7 – 1.5
Wordiekammen Formation	-33 – -32	5 – 10	1 – 2.5
Ebbadalen Formation and Minkinfjellet Formation	-32 – -26	7 – 40	0.5 – 2
Billefjorden Group	-27 – -24	2 – 6	2 – 5.5

since the associated  $\delta^{13}\text{C}$  of the aromatic fraction is lighter, the gammacerane index higher, and the Pr/Ph ratio lower than in the Billefjorden Group (Table 2). The Brucebyen Beds can be distinguished from the Billefjorden Group based on the  $\delta^{13}\text{C}$  values of the aromatic hydrocarbon fractions.

## CONCLUSIONS

Geochemical data from organic-rich shales and carbonates of Late Palaeozoic age outcropping in Svalbard suggests that:

(i) The fluvio-lacustrine intervals in the Mumien and Hørbyebreen Formations (Billefjorden Group) are active oil-generating source rocks in Spitsbergen. The organic material is mainly kerogen Type II, but there are indications that Type I kerogens occur in areas where lacustrine deposits are present. The TOC values range between 1 and 75 wt.%, and the organic-rich section has a cumulative thickness of more than 100 m. It can be distinguished from other Upper Palaeozoic source rocks in Svalbard by its high Pr/Ph ratios, heavy  $\delta^{13}\text{C}$  signatures and low gammacerane ratio.

(ii) The evaporitic Trikolorfjellet Member and the Minkinfjellet Formation in the lower part of the Gipsdalen Group have three potential source rock facies; shales, shales interbedded in evaporites, and organic-rich carbonates. The source rock potential is in Svalbard limited due to moderate TOC contents. The facies with the highest potential is the organic-rich carbonates with TOC up to 20 wt.%, which have a cumulative thickness of 8 m and which are confined to the deepest part of the onshore rift basins.

(iii) In the Ørn Formation -equivalent Wordiekammen Formation, a widespread organic-rich unit, 2–10 m thick, contains 1–10 wt.% TOC, and pyrolysis-gas chromatography data suggest that it is oil prone. The semi-regional distribution of the Brucebyen Beds along the western margin of the Barents Shelf suggests that it is a potential source rock, at least in this part of the shelf.

(iv) The presence of organic-rich facies in the Gipshuken Formation extends the stratigraphic range of potential source rocks into sections equivalent to the offshore Bjarmeland Group, particularly the presence

of organic-rich marine shales with an average of 10 wt.% TOC and hydrogen index values of between 200 and 400 mg HC/g TOC. This facies attains very limited thicknesses onshore Svalbard, but may be thicker in more distal offshore settings. However, at present its stratigraphic and geographical ranges are unknown.

(v) The Kapp Starostin Formation (Tempelfjorden Group) has no documented source rock potential in Spitsbergen.

(vi) It is likely that petroleum in the Barents Shelf can potentially be tied to organic-rich facies at formation level based on the gammacerane index, the  $\delta^{13}\text{C}$  value of the aromatic fraction, and/or the Pr/Ph ratio.

(vii) Carboniferous strata, where present, are likely to contain an effective source rock on the Barents Shelf, especially in the eastern part where burial has not completely transformed the organic matter into (presumably) dry gas.

(viii) For the Permian succession, the potential to supply a working petroleum system is more uncertain since intervals of good to excellent source rock are thinner and less predictable. The organic-rich intervals in the Gipshuken Formation are probably the best candidates; also, primary migration may occur within the carbonate facies.

(ix) Offshore mapping, preferably with the assessment of source rock quality based on seismic attributes in combination with depositional models, will be a key to the further evaluation of the Palaeozoic petroleum systems on the Barents Shelf.

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